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Attachment A

Staff Draft Report: 2001-2012 Electricity Outlook Report Executive Summary

Electricity and Natural Gas Committee Workshop

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CALIFORNIA ENERGY COMMISSION

2002 - 2012 Electricity Outlook Report

STAFF DRAFT REPORT

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Executive Summary

Scope and Purpose

The *2002-2012 Electricity Outlook Report* is a product of the Energy Commission's ongoing responsibilities to evaluate California's electricity demand and supply and to assess electricity system issues. Its purpose is to provide the Governor and Legislature an assessment of the state's electricity system over the next ten years and information on issues impacting state electricity issues. In addition, the results of this report will be available within the timeframe needed to meet the Energy Commission's obligation, under Section 3369 of the Public Utilities Code, to coordinate with the California Consumer Power and Financing Authority's development of its Energy Resources Investment Plan. This obligation was enacted in Senate Bill Number 6X, which was signed into law by Governor Davis. (Stats. 2001, 1st Ex. Sess. 2000 - 2001, ch. 10.)

This study helps to inform generation and demand decisions that could be made within the next two years by analyzing their possible intended and unintended consequences through the rest of the decade. The study necessarily examines the entire West, but focuses on electricity market trends and issues within California.

This report provides analyses that will help identify the choices and constraints, alternatives, implications and proposed actions that will further the goal of balancing electricity system reliability, reasonable prices and environmental protection. To meet this goal in a sustainable fashion, the long-term impact on suppliers, consumers and the environment must be carefully considered. Based on current supply and demand assessments, the Energy Commission staff believes that the near-term outlook for supply adequacy is promising. This gives California breathing room to examine the opportunities and choices for meeting its environmental, efficiency, and renewable resource investment goals.

Additional Related Reports

This report complements three other current Energy Commission staff reports on the electricity market. Two recently released staff reports provide near-term electricity forecasts. They are titled *2002 Monthly Electricity Forecast: California Supply / Demand Capacity Balances for January to September 2002 -- Documentation of Baseline Assumptions and Principal Uncertainties*, Publication # 700-01-002, and *California Summer Electricity Outlook: 2002 to 2004 -- Documentation of Baseline Assumptions and Principal Uncertainties*, Publication # 700-01-003. Both are available from the Commission's Website at www.energy.ca.gov. Additional context for this report is provided by the September 2001 staff draft report, the

California Energy Outlook: Volume I -- Electricity and Natural Gas Trends Report, Publication # 200-01-002. This latter report is currently under consideration for adoption as an Energy Commission policy report, pursuant to Section 25553 of the Public Resources Code.

The remainder of this "Executive Summary" provides an overview of the analyses, findings and conclusions discussed in the report.

Part I Electricity Market Developments - Setting the Stage

This section summarizes the factors that created the market volatility of the last several years and the events that have allowed the market to stabilize this summer. In addition, this chapter provides an electricity supply outlook of the expected near-term trends.

California's efforts to substitute competition for cost-based regulation in the generation sector of the electricity industry have fallen substantially short of expectations. The market trends in 2000 raised serious questions about the ability of the market structure to provide affordable and reliable electricity supplies for California's residents and businesses.

Weather conditions, tight supplies, increased costs of natural gas and high emission credit prices contributed to higher costs for electricity. These factors alone do not adequately explain the levels of prices seen in the California Independent System Operator (ISO) and Power Exchange (PX) markets from the summer of 2000 through the winter of 2001. Flaws in market design and rules are a major factor in the excessively high prices for electricity.

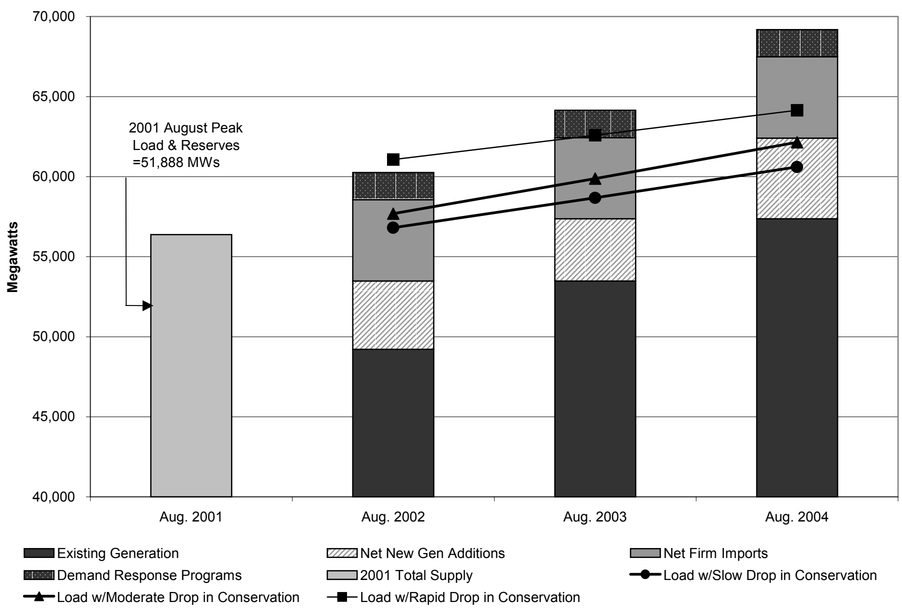
It became clear that stronger government involvement was required to protect the interests of California citizens. To address this need, the Governor developed an energy action plan and numerous Legislative bills have passed to stabilize the market. The ISO has been working with stakeholders to resolve a number of market design problems. The Federal Energy Regulatory Commission has also imposed a number of changes to the market structure to mitigate price and reliability problems.

Market structure changes, together with the negotiation of new long-term contracts, increased electricity generation facility construction, mandated efficiency programs and reduced energy consumption patterns have moderated the market volatility that was anticipated for 2001. Potential outages were averted during the summer 2001 and energy markets stabilized. However, many of the market structure changes actually compromised some of the intended goals of restructuring.

The electricity supply outlook for the next several years is even more favorable for maintaining reliability and moderating wholesale market prices (**Figure ES-**

1). This assessment is based on the assumption that many of the market-related problems that exacerbated the earlier supply problems are successfully resolved.

Figure ES-1
California Electricity Supply and Demand Balance 2002-2004
(1-in-10 Weather Impacts on Load Forecast)



Energy Commission staff finds that there will most likely be sufficient electricity supplies to maintain system reliability requirements through 2004. While the outlook has improved, many issues need to be resolved to maintain a reliable, reasonably priced and sustainable electricity system for the state overall and for specific regions within the state. The market structure that currently exists is an *ad hoc* arrangement, created to respond to the immediate needs of the crisis that was averted. If pending electricity related financial issues are not resolved and positive steps towards fixing the market structure are delayed, California will most likely face long-term system problems.

Policy makers now have to choose what market organization and market structure will best serve California. What should the new market look like? Will it still have a strong competitive flavor or will the State assume a larger role in procuring future power supplies? Does the State need to have a "reserve," and if so, what form should it take and how large should it be? These questions need to be carefully analyzed and thoughtfully addressed.

Part II: Supply – Demand Scenarios

This section presents the component analyses comprising the overall electricity supply and demand assessment for the next decade. Part II-1 examines the uncertainties associated with forecasting the California electrical system peak demand and energy requirements, given the substantial reduction in consumer demand in response to the recent electricity crisis. Part II-2 examines the uncertainties associated with forecasting energy spot market prices and new power plant completions under a variety of supply and demand scenarios. Even with much of the energy demand served under bilateral contracts, spot market prices remain an important price signal for developers of new supply- or demand-side electricity resources. The goal of this analysis is to estimate spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants. Part II-3 examines the potential risks that near-term (2003) capacity resources may be inadequate to meet demand.

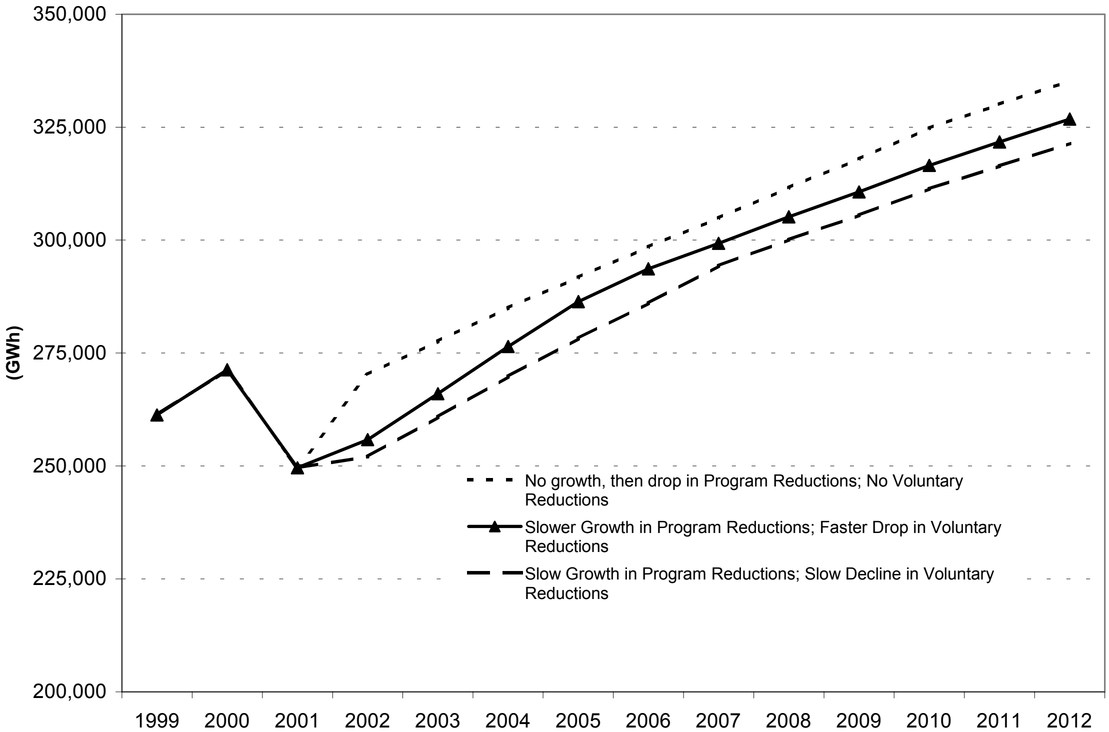
Part II-1: California Electricity Demand

The summer of 2001 saw an extraordinary reduction in peak demand. Even though the summer of 2000 and 2001 were both about the 25th hottest years (with high ranks denoting hotter conditions, 2000 was ranked 82nd out of 106 years and 2001 was 83rd out of 107 years), actual peak demand in 2001 was substantially lower than the summer 2000 peak demand. There were 29 days during the summer of 2000 when demand exceeded 40,000 MW. There were only 6 of these high demand days during the summer of 2001.

Recent events increase the range of uncertainty in the forecasts of electricity consumption and demand trends. In particular, it is too early to tell the extent to which the demand reductions of 2001 will continue into the future. Monthly peak demand in 2001 was significantly lower than would be expected, and analysis has only recently begun to estimate how much of this demand reduction was a result of technical, permanent changes and how much was due to behavioral or other temporary changes. Adding to the analytic dilemma, the full impact of rate surcharges and newly legislated programs have not yet been seen. In addition, it is not clear what, if any, effect recent events will have on economic growth in the state — and on energy growth.

The uncertainty about the causes of the demand reduction in the summer of 2001 contributes to increased uncertainty about future electricity use trends. To capture this uncertainty about future electricity use, the staff developed several possible patterns of future trends for the persistence of summer 2001 demand reductions. These patterns were based on alternative assumptions about the level and persistence of voluntary impacts and permanent, program impacts (**Figure ES-2**). These three demand scenarios provide the demand forecast for the staff's different analyses throughout this report.

Figure ES-2
California Electricity Consumption Scenarios



The following summarizes the staff analysis of expected California energy consumption over the coming decade:

- Uncertainty about future economic conditions makes forecasting highly uncertain.

- There is uncertainty regarding why summer of 2001 demand reductions occurred although electricity price increases, programs, and volunteerism are factors reducing summer 2001 demand.

- Impacts of demand reduction programs may increase slightly but, unless there are new campaigns or crises, voluntary demand reductions will likely decrease over time.

As well as detailed data about customer use, information is needed to determine why customers did what they did. Surveys need to be done to analyze how much of the reduction was due to customer behavioral and permanent response to legislated programs, how much was due to media campaigns, and how much to other factors. A better understanding of 2001 will reduce some of the uncertainty in the projections of future demand reduction.

Part II-2: Energy Market Simulations

Reserve margins in California have historically been set by regulators so as to ensure an adequate level of system reliability during peak hours. Reliability requires that sufficient in-state generation and imports is available despite possible power plant and transmission line outages and adverse water conditions, which limit hydroelectric generation in both California and the Northwest. Regulators have historically set reserve margins so that the inability to meet peak demand is no greater than one day in ten years; this has required planning reserve margins of 15 – 22 percent.

Under deregulation new capacity is constructed in response to market conditions rather than regulatory fiat. In the long run, reserve margins will tend towards levels that yield prices for wholesale electricity that will be sufficient, in conjunction with earnings in ancillary services markets and from "must-run" contracts for local reliability, to compensate investors in new facilities for the risks that they assume.

During the first half of 2001, the California Department of Water Resources signed long-term contracts for wholesale power that will meet a substantial share of the energy needs of investor-owned utility (IOU) customers. These contracts, together with energy from utility-owned nuclear and hydroelectric generation and Qualifying Facility (QF) contracts, greatly reduce the share of energy purchased in spot markets to meet IOU customer demand. Accordingly, spot market electricity prices will play a significantly smaller role in determining the wholesale cost of energy for IOU customers.

Spot market prices will continue to influence decisions to build new generation capacity and to retire existing facilities. Low spot market prices--those that do not result in profits high enough to warrant investment in new plants--deter capacity expansion. If low enough, spot prices encourage the retirement of plants that cannot cover operating costs. High prices signal the need for new capacity and its profitability. The goal of this analysis is to obtain estimates of spot market prices, which can be used to assess the likelihood of additional capacity expansion and the retirement of existing power plants.

The spot market prices yielded by the simulation studies indicate that the addition of expected new capacity during 2002 - 2005 is apt to drive spot market prices to levels that will render many existing power plants unprofitable and discourage further construction. However, there are factors that may encourage building even in the face of low prices in the short-term, listed as follows:

- Concerns that resources needed to enter the market may become increasingly scarce encourage the addition of new capacity. These may include desirable locations for power plants, permits to construct and operate, emissions and water use permits, access to transmission lines and gas pipelines, etc.

- Demand growth may be under-estimated; the conservation observed in 2001 may be seen as transient.

- The certification and construction of new combined cycle power plants takes two to four years. Developers may be unable to back out of existing commitments when market conditions change. For example, developers may have to commit to purchasing turbines well before delivery, plant construction, and operation.

- Developers may anticipate that competitive forces will lead to the retirement of a significant share of existing capacity during the next three to five years. Should this happen, those building now will be the beneficiaries of the higher prices that result.

The simulation results also indicate that low prices from 2003 onward may be an incentive to retire existing units. It is unlikely, however, that a substantial amount of capacity will be completely retired and dismantled in the WSCC during 2002 – 2004. Uncertainties related to the amount of new capacity coming on-line, the return of electricity demand to previous trend levels, and regulation and market structure will contribute to uncertainty regarding spot market electricity prices, and discourage the closure of generation facilities. Owners are apt to incur the costs required to keep less-efficient plants available for operation given the *possibility* of adequate revenues during the next couple of years, if not long-run profitability. Low prices in 2003 and 2004, would lead to reduced operation for many plants. This reduction in their competitiveness will encourage their placement into long-term reserve, and increased consideration being given to their retirement

The construction of expected new generation facilities during the next three to four years is likely to create a surplus of generation capacity, and lead to average annual wholesale spot market prices in the neighborhood of $30/MWh. This price is below that necessary to yield desired returns to investment in new, efficient gas-fired combined cycles. New gas-fired generation will reduce average summer prices both in absolute terms and relative to winter prices. It will also reduce the differential between peak and off-peak prices.

The addition of new capacity and resulting downward pressure on prices will greatly reduce the need for and profitability of older, large gas-fired units presently used to meet baseload demand. The efficiency and flexibility of smaller units currently being permitted for service further threaten the profitability of older, large plants by both operating in their stead and reducing the number of hours that the least efficient peaking units can set very high spot market prices.

As gas-fired power plants become an increasingly large share of the generation resources in California and the WSCC, the price of natural gas will have an increasingly larger role in determining the spot market price of electricity.

Overbuilding and delays in retiring older facilities are part of a "boom-bust" dynamic that is an inherent part of the structure of the market. The amplitude and length of these cycles cannot be known in advance, but must be considered in market design.

Part II-3 Quantifying the Risk of Capacity Shortages

Generally, the power system is said to have adequate capacity if it has enough generation and transmission resources to meet the customer demand and to maintain a reserve of capacity for contingencies. But it would be prohibitively expensive to build an electric generation and transmission system that would *never* experience a service outage. Instead, we seek to minimize outages within a constraint of reasonable cost, thereby accepting some risk of outages.

This section presents a quantitative assessment of the level of risk of capacity shortages during the summer of 2003. The near-term capacity assessment of Part I, which concludes that we *most likely* have sufficient capacity in 2003, does include a risk assessment. Some conservative assumptions were deterministically made to ensure the conclusions would be robust with respect to some possible but less likely outcomes. For example, the adequacy of capacity resources was assessed against peak demand levels expected to occur under a variety of possible future temperature conditions. Supply adequacy was assessed under temperature conditions that occur once every two years, once every five years, and once every ten years. This section builds on that and tries to quantify just *how likely* is the risk of capacity shortages in 2003. Our results provide some help in answering questions such as: What risk of supply shortages are we facing in the near term? Do we have "enough" capacity? How much additional risk will the next increment of capacity avoid? What are our options for managing the risk, and how does their risk management performance compare?

This section quantifies how uncertainties associated with specific key risks that affect supply adequacy contribute to the overall risk of outages. We assessed one demand-side risk to supply adequacy: the effect of temperature variations on peak demand. And we assessed three supply-side risks: the effect of hydrological conditions on the availability of hydroelectric generation capacity, the effect of potential construction delays on the availability of new power plant capacity, and the effect of aging on the rates at which generation and transmission facilities are forced out of service. This section also quantifies how risks of capacity shortages vary across the different transmission zones within the interconnected Western grid.

Staff analyses show that with all current resources in operation and with the expected new resource additions, California has enough power to meet forecasted peak demand in the summer of 2003, on average. But California could face a combination of less likely unfavorable circumstances that could bring risks of power supply shortages (in the form of lower than required reserves or even outages.) The risks of power supply shortages in 2003 vary for different parts of the state: from little to no risk for Northern and Central California and the largest municipal utilities- LADWP and SMUD, to low risk (1.3 percent) for Southern California, to a noticeable level of risk (7 percent) for San Diego, and to a significant level of risk (13.7 percent) for San Francisco.

Aging equipment, resulting in an increase of forced outages of power supply equipment, increases supply adequacy risks. Sensitivity studies show that risks of power shortages increase much faster than increases in the forced outage rates of the power supply equipment. For example, in Southern California, when forced outage rates double, risk increases 7.5 times, from 1.3 percent to 10 percent. [When we say "forced outage rates double", we mean that all individual units' unique observed rates of forced outages, which may range from 1 percent to 5 percent, are assumed to be double these observed values in the sensitivity study]. When individual unit forced outage rates are tripled, Southern California's risk of supply inadequacy increases 26 times, from 1.3 percent to 34.7 percent.

Construction delays negatively affect supply adequacy, increasing risks dramatically in areas where new construction is underway or proposed. For example, with moderate delays in construction, the San Diego area's risk of outages is more than doubled, from 7 percent to 14.7 percent. This suggests the importance of bringing planned new power plant additions online in California as scheduled.

Some have posited that a competitive market requires an excess of capacity of 30 percent or more. The main Southern California regions will not be able to provide such a reserve margin by 2003 unless measures beyond the currently proposed generation projects can be implemented to make an additional 10,000 to 15,000 megawatts of supply or demand reduction available to California. Market conditions are not likely to provide incentives for this to occur.

Part III: Issues Analyses

This section presents discussions and analyses of a variety of issues important to the development of a workable electricity market. Part III-1 deals with the fundamental question of how well the existing energy market can be expected to maintain the adequacy of the electricity system at reasonable prices, and what market changes might better achieve that goal. Part III-2 examines the economic, reliability and environmental influences that complicate "power plant life management" decisions (i.e., whether to run, refurbish, repower, or retire existing power plants). Part III-3 provides an assessment of future retail electricity rates by utility and customer class, showing how the various components of costs each contribute to the total rate. Part III-4 examines the characteristics of the demand response potential, and suggests a specific mix of load curtailment programs to ensure reliability in the year 2002. Part III-5 discusses how recent events and the current *ad hoc* market arrangements have affected the renewable generation industry and issues related to incentive programs for developing renewable generation resources. Part III-6 describes the progress the Energy Commission has made in licensing new power plants, issues that may affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

Part III-1: Electricity Markets and Capacity Supply Adequacy

While the supply-demand outlook is reasonably resilient for the near future, the current market structure must be changed, because it cannot produce adequate generation in a timely and efficient manner. The current market structure is an "*ad hoc*" arrangement, pieced together to respond to the numerous short-term crises. These short-term stresses revealed fundamental problems in California's overall system. Unless modifications are made, by 2005 California will be headed back into supply and demand conditions likely to produce tight supplies, price volatility, reliability concerns, and consumer dissatisfaction. Policy-makers now have to choose what market structures will best serve California.

This section examines how alternative markets can be structured to motivate the addition of timely new generation to reduce price volatility and contribute to reliable service. It examines three alternative approaches to the supply side, and concludes that changes on the supply side are necessary but not sufficient to insure an adequate amount of generation in the system for reliability and reasonable prices. Without modifications to the retail pricing and to the wholesale market, a sustainable generation market is not feasible.

The current system, based on the theory of a purely competitive market, relies on energy-only payments, augmented by payment for ancillary services and must-run requirements. For this system to attract new generation, reserve margins have to narrow enough that prices rise and the likelihood of excessive price spikes increases. Three alternative supply designs are evaluated: installed capacity payments tied to energy purchases, requiring loads to obtain reserve capacity, and regulated ownership of capacity whether through government-owned facilities or utility ownership of reserve capacity.

None of these options is perfect. Decision-makers must take into account the strengths and weaknesses of each in setting a course. If it were feasible, purely competitive wholesale markets would yield the lowest average prices, but are subject to dramatic price swings. So far, no one has designed a purely competitive capacity market that works.

A mandated reserve structure yields less variable prices, but has higher average prices. This structure relies on regulators, not prices, to incent new capacity. If regulators set the requirement too low, the market will not have sufficient reliability. If they set it too high, then the cost of electricity will be higher than it needs to be. And, the required reserve margin that yields the lowest system costs depends on the degree to which consumers respond to changing electricity prices. This means that it is difficult to set the capacity requirement efficiently.

The second option is a market-based incentive payment for reserves that is intended to provide market signals concerning investment in generating capacity. As reserve margins fall, this payment increases, signaling to generators that they should build new plants. Evidence in the United Kingdom, suggests that this factor is a source of market power rather than an economic incentive to build new generation. Day-to-day and seasonal instability in this payment make it difficult for generators to use it to determine how much new capacity to build.

A cost-of-service design drives out private investment and requires an ongoing commitment of regulated funding from loads. If the State decides to participate in the market for generation, it would exercise considerable control over the amount of generation coming on-line. Such cost-of-service reserves, whether owned by the state or by utilities, would stave off potential price spikes for 2002 - 2004 but would also have the undesired outcome of driving out private investment. There seems to be a narrow range of participation by the State in supplying peaking capacity, beyond which the private investors may permanently defer future capacity investments. Eventually, this will lead to inadequate generation and price spikes. If the State chooses to go this route, it must make a long-term commitment in the power market.

It may be desirable for the state to wait until the uncertainty surrounding the wholesale market structure in California is resolved before taking this plan of action. While state-owned generation would lessen price volatility in a purely competitive market, it would be counter-productive in a mandated reserve margin or installed capacity payment structure.

A good market design will provide benefits to consumers and suppliers, allow for efficient market monitoring, reduce the need for government intervention, and promote competitive innovation. The market structure must be compatible with other market designs in the Western United States. California is an integral part of a regional market.

The supply-side and retail market structures are interdependent. Effective generation price signals cannot take place independently of the retail market. Consumers must choose to consume or not consume based on the prices that reflect market conditions. They may make this choice directly through their own real-time pricing actions or through their utilities/aggregators that would hold a hedged portfolio to provide rate stability.

Another example of changes on the demand side that will facilitate a more efficient supply market is flattening the steep summer peak through energy efficiency or higher rates for peak power. Reducing the needle peak would reduce the need for a large number of rarely used generation to try to make money in only the highest 200 hours of the year. A more even annual profile will reduce the boom-bust cycle, give generators more hours to compete and a better chance of recovering costs, and will require fewer power plants.

Generation adequacy will be facilitated if the wholesale day-ahead, hour-ahead, and real time spot markets use commercial models that reflect physical constraints and efficient dispatch. Generators must have an obligation to perform according to schedules. Many researchers urge that simultaneous, nodal markets are essential for an efficient market.

A coherent market design will need to be advocated in multiple forums, including FERC, the Independent System Operator, the California Public Utilities Commission, utility board rooms, the California Power Authority and stakeholder groups. New California laws will be needed to facilitate a new design and to replace the many short-term fixes that were legislated to handle immediate crises. While needed at the time, such approaches may be counter-productive in a redesigned market. All parties interested in a revitalized California electricity market should be engaged in this market redesign.

Part III-2: Power Plant Life Management:

Power plant life management refers to the physical and operational changes made by the owner over the life of the plant in reaction to changing economic and regulatory circumstances. Such changes can range from a complete replacement of the old plant, a repowering to increase its capacity, refurbishing it to maintain its current operating levels, letting some performance deterioration occur, putting it in short-term or long-term standby reserve (mothballing), or even retiring the plant.

State policies supporting energy efficiency, demand responsiveness and generation from renewable sources and advanced gas-fired turbines are based, at least in part, on achieving fuel use savings and emissions reductions associated with such economic displacement. However, State energy policies have refrained from mandating outright retirements of older generators, acknowledging the fact that even units targeted for reduced usage still provide valuable public benefits. For example, the capacity from such units may be necessary to maintain local system reliability and voltage support, to mitigate locational market power, to moderate the price of ancillary services, to avoid the cost of prohibitively expensive alternatives, or to provide a capacity reserve. Even if used infrequently, older plants provide insurance against extreme demand peaks driven by unusually high temperatures or against severely reduced generating supplies from drought conditions or large simultaneous maintenance and forced outages of generation and transmission facilities.

To understand the relative performance of the state's aging power plants from a reliability and environmental perspective, one would need to collect and compare data on these performance factors for each power plant unit. We would measure the system reliability attributes of power plant units by their performance with respect to specific reliability-related criteria: forced outage rate, capacity factor, maintenance outage rate, dependable capacity, plant age, possession of a reliability-must-run (RMR) contract with the ISO, and location of the plant in a generation-deficient or transmission-constrained area. We would measure the environmental protection attributes of power plant units by their performance with respect to specific environmental criteria: the cooling method used, water source, and NO_x emissions.

Given the diverse reliability and environmental factors considered, each factor would need to be given a weight and each power plant unit would end up with a weighted value for each factor. The weighted values for all factors would then be combined into a score for the unit. Because their roles differ in meeting load in the bulk power market, staff would compare utility boilers, gas and oil turbines, and combined cycle units separately. Once grouped together, the individual power plant units would be ranked according to their individual unit total scores. The poorest ranking units would be the best candidates for the next stage of the evaluation--the detailed, site-specific evaluation of the costs, benefits and risks resulting from the retirement or reconfiguration of individual units.

Because of the time required to develop and discuss this approach, and the absence of public input on weighting factors and their policy implications, staff did not perform such an analysis at this time. If such a screening analysis were performed, the next step would be to closely investigate the costs, benefits and risks resulting from the retirement or reconfiguration of individual units identified as potential candidates by the screening. Such studies might begin with the units this screening analysis identifies as the most suitable candidates, for one reason or another. Conversely, such efforts probably should not be focused on units not so identified, unless additional relevant information is available.

The ultimate purpose of this effort is to improve our understanding of the potential for power plant retirements over the decade in an effort to make our overall supply and demand balance more robust. A second future purpose is to identify a methodology that could be used to identify a potential cohort of power plants that might deliver greater public benefits, on balance, if a retirement or other plant life management option were chosen instead of continuing the current operational status. The immediate purpose of this section is to describe a screening analysis methodology for identifying specific potential candidates for retirement or other plant life management option, and to elicit comments on that methodology.

Power plants are operated to the economic advantage of their owners, whether the owners are independent power producers, investor-owned utilities or publicly-owned utilities. But power plant operations are directly constrained by utility practice or regulations to ensure the reliability of the electric system and avoid unacceptable economic, public health and environmental impacts.

If changes to the observed or expected operations of power plants in the system will provide local or system-wide public benefit, but such changes are not expected under existing market conditions, then the State may act to secure these benefits either by changing the regulatory constraints or by providing incentives for the owner to change operations voluntarily. But the reliability, public health and environmental effects of power plants are complex and dynamic. Site-specific analysis of the costs and benefits of alternative means to secure public benefits from operational changes is necessary to ensure any action taken achieves its goal and avoids negative unintended consequences. Indirect actions to achieve a goal are less likely to be successful than direct actions.

Units with poor reliability performance are of less value to their owners than other facilities, all other things being equal. Therefore, staff would not expect it to be necessary for the state to provide incentives or redesign constraints to effect a change in operations of these units.

If a unit generates adverse environmental impacts, but makes a contribution to reliability, then the State may offer incentives to encourage the owner to apply controls to mitigate such impacts.

If a unit rates poorly with respect to reliability (has little reliability value to the system), but does not have a significant environmental impacts, then the State may be content to let economic displacement of the unit diminish its use over time.

If a unit performs poorly on both environmental and reliability criteria, then the State may have an additional interest to see the unit retired external to the interests of the owner. It may be preferable that market forces effect the economic displacement of the unit, or the State may offer incentives to the owner.

Before offering any incentives, site-specific analysis of the costs and benefits of alternative means to secure public benefits should be conducted. If benefits exceed the costs, and there are no alternatives to achieve the same level of benefit either more directly or at lower cost, then the incentive would be warranted.

Part III-3: Retail Electricity Rates

This section presents the Energy Commission staff outlook for electricity retail rates for California investor- and publicly-owned utilities for the years 2002-2012. In this outlook, the staff provides estimates of the retail electricity rates that typical consumers may pay, given projected energy prices, utility plans and programs, and regulatory decisions.

The purpose of this outlook is to provide consumers, market participants and policy makers with a basic understanding of future electricity rates. This outlook is not an absolute prediction of what the future electricity rates will be, since future regulatory actions, technology development, or market changes may alter key fundamental assumptions. The projection uses the best available information and a set of assumptions the authors believe are probable and realistic. However, many factors influence prices.

California's electric industry is currently undergoing dramatic changes. Electricity rates for investor-owned utilities (IOUs) and municipal utility customers have increased dramatically during the current year. For example, the CPUC approved two rate increases for the IOUs, a one-cent average rate increase in January and another three-cent increase in May of this year. Similarly, governing boards of municipal utilities have approved overall rate increases to replenish their rate stabilization funds and energy cost adjustments to recover their fuel and energy cost.

Future electricity rates for the IOUs depend on the regulatory decisions of the Federal Energy Regulatory Commission (FERC), State Legislature, the Governor, and the CPUC, rather than the spot market prices. For example, if FERC orders refunds to the State utilities for alleged overcharges by merchant generators and energy traders late last year and early this year *and* if the refunds are distributed to ratepayers, then rates would likely decline.

Since municipal utilities have long-term contracts for energy, their future electricity rates depend more directly on the price of natural gas and to some extent the need to replenish their rate stabilization funds. Municipal rates, on the other hand, will likely remain constant for the next few years, but could increase in the later years to reflect energy costs and inflation.

Under the current circumstances, retail rates for IOU customers will most likely increase in the 2002-2003 period. A comparison of the utility average electricity rates in **Table ES-1** shows that (real $2001) rates for IOU customers are generally higher than rates for the larger municipal utility customers in the initial years, but become comparable in the later years. A rate decrease is unlikely, unless the Federal Energy Regulatory Commission (FERC) orders merchant generators and energy traders to refund the State utilities for overcharges incurred during the fall and winter of 2000-2001. However, a small rate decrease is possible after 2003 for most IOU customers. If regulators decide that ratepayers should bear the IOUs' debt, rates would likely increase gradually up to an average of 13.0 cents/kWh in the 2002-2005 period.

Table ES-1
System Average Electricity Rates in Cents per kWh ($2001)

Year	PG&E	SCE	SDG&E	LADWP	SMUD	Burbank	Pasadena	Glendale	GDP Deflator
2002	10.5	13.8	13.2	9.6	8.9	11.8	11.7	11.8	103.0
2003	12.4	14.0	13.5	9.4	8.7	11.6	11.4	11.5	105.5
2004	11.8	14.5	12.9	9.6	8.3	11.9	11.7	11.8	108.3
2005	11.9	13.7	12.6	9.9	8.5	12.3	12.0	12.2	111.2
2006	12.0	13.6	12.9	10.2	8.8	12.6	12.4	12.5	114.0
2007	11.8	13.3	12.6	10.5	9.1	12.8	12.8	12.9	116.9
2008	11.2	12.7	11.9	10.8	9.3	13.0	13.1	13.2	119.6
2009	10.9	12.4	11.7	11.2	9.7	13.2	13.6	13.7	123.7
2010	10.7	12.1	11.4	11.6	10.0	13.4	14.0	14.1	127.4
2011	10.6	11.9	11.3	12.9	10.4	13.6	13.9	14.6	131.5
2012	10.4	11.6	11.0	12.4	10.9	13.7	13.7	15.1	135.7

Municipal utilities are likely to maintain constant retail electricity rates for their customers during the 2002-2003 period. Rates for municipal utility customers after 2003 would most likely reflect the utilities' cost of generation, which under current projections will increase slightly every year through 2012.

In addition to forecasting trends in average system rates, Part III-3 presents information about the component costs of rates and forecast rates by customer class for each of the state's utilities. Examples of these more detailed findings include:

- Average electricity rates for IOU small commercial customers could reach up to 19 and 20 cents/kWh in 2003.

- Energy generation costs reflected in the rates of residential customers of PG&E, Edison and SDG&E amounts to approximately 50 percent of the rate. However, for medium commercial and industrial, it can account for up to 80 percent of the rate.

Part III-4: Developing Demand Responsive Loads

The experiences of May 2000 through May 2001 reveal the potential problems of dysfunctional electricity markets. Excessive prices were being demanded in the marketplace and drastic consequences have resulted. This chapter discusses the characteristics of the demand responsive potential, and suggests a specific mix of load curtailment programs to facilitate ensuring reliability in the year 2002.

Demand response can come from real-time price (RTP) tariffs or dispatchable load curtailment programs that enable end-users to respond to market prices or to adverse system conditions by reducing loads, respectively. Customers on real-time price tariffs either save money by reducing consumption in high-priced periods or shifting loads from high- to lower-price periods. Customers on load curtailment programs respond to incentives to reduce loads when system conditions trigger load curtailment program operation. Both forms of demand responsiveness reduce loads when market prices and/or system conditions warrant this action.

Reducing exposure to excessive market prices is likely to be more cost-effective through time than avoiding markets entirely by relying upon command and control decision-making. Reducing exposure is not the same as eliminating exposure. Reducing exposure to excessive prices admits that an occasional dose of high prices in the right circumstances might be the most cost-effective way to satisfy net electricity demand with generation.

There are up to 5,000 MW of load that can be expected less than 200 hours per year. It is unreasonable to expect that 5,000 MW of generation will be available from the bulk energy market to satisfy such loads. Many market analysts believe that fundamental market redesign or additional capacity payments are needed to ensure that resources are available at peak load conditions.

Energy Commission staff proposes that 2,500 MW of planned demand responsive capability should be obtained from demand response-load curtailment programs and tariffs. We propose this level for two reasons. First, this level should be sufficient to develop several different load curtailment programs and real-time price rates. Offering sound load curtailment programs to end-users and conducting a careful review of their response to marketing efforts and then the behavior as the programs are operated should provide real data with which these questions can be evaluated for a longer-run solution. By failing to offer a sufficiently large set of load curtailment programs we will never gain the experience to know the extent to which these tradeoffs are acceptable to substantial numbers of customers. Thus, pursuing load curtailment program experience can help to firm up corollary benefits described in our use of the six comparison criteria.

Second, sole reliance upon generation to provide peaking resource needs violates our flexibility criteria. Committing too much of resource additions to peakers is imprudent given the potential that load curtailment programs and real-time price rates appear to offer. Excessive commitment to peakers may drive out lower cost, more environmentally friendly and economically efficient solutions using real-time price tariffs. The proper planning decision under these conditions is to minimize long term commitments, and to explore the options further.

Making short-term commitments to load curtailment programs achieves the overall goal of 2,500 MW of demand responsive capability, and can lead eventually to greater reliance upon real-time price tariffs and less reliance upon load curtailment programs**.** For next summer, at least 1,500 MW of interruptible load program are already in place. The Energy Commission has already proposed specific modifications to two existing, CPUC-authorized load curtailment programs that would enable 1,000 MW of increased load curtailment program capability to be achieved. The Energy Commission has also suggested imposition of a non-bypassable reliability surcharge, at the rate of $0.001/kWh for all consumption, be levied on all distribution customers of the three IOUs. In the longer run, the Energy Commission recommends the CPUC adopt real-time pricing tariffs and that the State organize agencies and the ISO to provide the real time pricing signals needed for such tariffs.

Part III-5: Effects of Renewable Generation Initiatives

Before the electricity market crisis of 2000, the Energy Commission's Renewable Energy Program was instrumental in increasing the supply and demand of renewables within the market-based system of AB 1890. Developers came to the Energy Commission with more proposals for new renewable generating facilities than could be funded. In June 1998, the Energy Commission's Renewable Energy Program held a $162 million auction that could yield 551 MW (nameplate) of new renewable capacity.

In addition to promoting the development of new renewables, the Energy Commission provided funds to ensure that existing renewables would stay online. In the mid-1990s, renewable capacity decreased by 300 MW because of reduced payments from the utilities. The Energy Commission provides incentive payments to Existing Renewable facilities when the utility payments are less than a target price. The 300 MW of lost renewable generation in the mid-1990s returned online by 2001. Other existing facilities maintained their output or repowered their facilities, when otherwise they may not have been able to do so.

Besides supply-side incentives, the Energy Commission also built demand for renewables by providing a per kilowatt-hour credit to customers who purchased renewable energy from a direct access electric service provider. At the market's peak in May 2000, over 216,000 customers (2 percent of all IOU customers and 97 percent of all direct access customers) received a credit of 1.25 cents/kWh on their electric bill for purchasing renewable energy.

The electricity crisis now threatens the long-term viability of California's renewable resources. The bankruptcy of the Power Exchange and the financial difficulties of the utilities have reduced opportunities for new renewable power plants to sell their generation. Assembly Bill 1X authorized the Department of Water Resources to purchase electric power for the customers of California's Investor Owned Utilities. The Department of Water Resources signed long-term contracts to supply most of the power to meet IOU customers' needs, but signed relatively few contracts with renewable generators. Another provision of Assembly Bill 1X ordered the Public Utilities Commission to suspend direct access.

Because these developments created concern over the persistence of the demand for renewables, consumer advocates and environmentalists proposed a Renewable Portfolio Standard, whereby electricity retailers would be required to purchase a certain percentage of their power from renewable resources. In an effort to spur the development of new renewables, the Energy Commission held two more auctions for $40 million each, one in November 2000 and the other in September 2001. Combined, these two auctions yielded another 770 MW (nameplate) of potential new renewables. Whether these projects, as well as some first auction projects that are not yet online, come to fruition depends on whether they can find a buyer for their power.

In summary, current conditions are not favorable to renewable generation. Potential buyers for new renewable resources are few. Direct access is closed to new customers and it is unknown whether it will be restored and whether or not the Renewable Portfolio Standard will be enacted. The Department of Water Resources has purchased only limited amounts of renewable generation and has already purchased enough power to meet most of its needs. The investor-owned utilities are undergoing financial difficulties and the remaining electric service providers cannot sign up new customers. The Power Authority has announced its intentions to negotiate with generators, but has made no firm commitments to buy renewable generation. Generators do not know whether they may be selling to meet a Renewable Portfolio Standard or to a renewables-only direct access market. Some new renewable generation funded through the Energy Commission's auctions may never get built due to the current uncertainty over who will buy this generation. To respond effectively to changing conditions, the Energy Commission needs to maintain its flexibility in determining the allocation and distribution of funds for its efforts in renewable energy.

The Energy Commission will continue to support emerging renewable resources for onsite generation such as photovoltaics, small wind turbines, solar thermal electric, and fuel cells that utilize renewable fuels because of their technical potential. The cost of photovoltaic systems has decreased substantially in the last three decades and this trend will continue. Further support for emerging renewables will stimulate demand for these technologies, which in turn, will stimulate that industry to devise ways to reduce costs such as training additional installers and technological innovations that simplify the manufacturing process. Recently, demand increased for renewable on-site generation in response to California's energy crisis. In its Investment Plan for renewables, the Energy Commission states that it hopes one percent of all electricity consumed in California will come from emerging renewable resources by 2006.

The legislation extending the Energy Commission's renewables program stated renewables would add needed generating capacity while promoting fuel diversity and reducing the need to burn fossil fuels. The Energy Commission has established a target of meeting 17 percent of California's energy demand with renewables by 2006. Additional renewable resources can come on line and meet these goals if the Energy Commission continues to have flexibility in administering its funds and if viable demand for renewables materializes.

Part III-6: Siting Issues

This section describes the progress the Energy Commission has made in licensing new power plants, including changes made to the Energy Commission's licensing process to expedite the licensing of new power plants. It also describes current and expected trends related to the number, size, type and location of new power plants and issues that may affect the ability of power plant developers to obtain timely approval; and measures needed to address these siting issues.

The Energy Commission was successful in bringing new power plants on line to help avoid electricity outages during the summer of 2001. The Energy Commission's efforts during the electricity emergency to conduct early site screening for the emergency projects, to assist developers in processing project compliance amendments, to assist developers in overcoming roadblocks to completing construction, and to license new power plants were important in bringing this new capacity on line.

Forecasting the supply and demand balance requires more than a calculation of demand and supply. It also requires the assessment of the locations of demand increases and of new generation resource additions to avoid local transmission system congestion and generation deficiencies. Integrated electricity planning, which considers both transmission and capacity solutions should continue so the most economically efficient and reliable supply/demand balance is reached. The Energy Commission should support efforts to develop a state planning effort for new generation and transmission lines to address congestion, system reliability and efficiency issues.

Although the Energy Commission licenses transmission lines needed to interconnect a power plant under its review to the transmission system, other transmission projects are permitted by multiple agencies. The overlap, inconsistency and inefficiency created by such permitting pose potential constraints to expedited licensing of new generation and transmission projects. To address this problem, the Energy Commission has previously supported consolidation of transmission line permitting in California.

Environmental and permitting issues potentially constrain the Energy Commission's ability to efficiently site new capacity additions without resulting in contested proceedings or potentially significant adverse impacts. These issues include the availability of emission offsets, water supply and water quality impacts, the timing of federal permits, land use conflicts, transmission congestion, and natural gas supply constraints. Working with other agencies, The Energy Commission should provide guidance regarding these constraints on licensing new capacity.

Please note that we have only put the "executive summary" on line in this attachment.

The **entire** **Staff Draft: 2002-2012 Electricity Outlook Report** is available to download as a separate, complete document from the documents page at:

www.energy.ca.gov/electricity_outlook/documents/

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California Energy Commission

ATTACHMENT B

Tentative Agenda

December 11, 2001 Committee Workshop
Starts at 10:00 a.m., Hearing Room A

10:00 a.m.	Committee Opening Remarks	10 minutes
10:10 a.m.	Staff Presentation	30 minutes
10:40 a.m.	Public Comments or Presentations	30-95 minutes
12:15 p.m.	Committee Closing Remarks	10 minutes
	Workshop Adjourned	